NON-PROPRIETARY

6-2500-10601-2
PUC Docket No. E,G 002/PA-95-500

STATE OF MINNESOTA

OFFICE OF ADMINISTRATIVE HEARINGS

FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of the Contested Case Portion of the Petition of Northern States Power Company for Approval to Merge with Wisconsin Energy Corporation

FINDINGS OF FACT, CONCLUSIONS AND RECOMMENDATION

PRE-MERGER ELECTRIC REVENUE REQUIREMENT

The "Pre-Merger Revenue Requirement" portion of the contested case proceedings in this matter came on for hearing before Administrative Law Judge Richard C. Luis on December 2 and 3, 1996 in the large hearing room of the Public Utilities Commission (PUC) in St. Paul, Minnesota. The record closed on January 15, 1997.

Appearances: David A. Lawrence, Esq., 414 Nicollet Mall, Minneapolis, MN 55401 and Samuel L. Hanson, Esq., 2400 IDS Center, Minneapolis, MN 55401, appeared on behalf of Northern States Power Company (Company, NSP); Brent L. Vanderlinden, Assistant Attorney General, 1200 NCL Tower, 445 Minnesota Street, St. Paul, MN 55101, appeared on behalf of the Minnesota Department of Public Service (DPS); Eric J. Peck and Eric F. Swanson, Assistant Attorneys General, 1200 NCL Tower, 445 Minnesota Street, St. Paul, MN 55101, appeared on behalf of the Office of the Attorney General (OAG); Joseph M. Paiement, Esq., 5636 Sturgeon Lake Road, Welch, MN 55089, appeared on behalf of the Prairie Island Indian Community (PIIC); Jay M. Quam, Esq., 1100 International Centre, 900 Second Avenue South, Minneapolis, MN 55402, appeared on behalf of Cooperative Power Association (CP); and Betsy Engelking and Louis Sickmann, 350 Metro Square Building, 121 Seventh Place East, St. Paul, MN 55101, appeared on behalf of the Staff of the Public Utilities Commission.

NOTICE

Notice is hereby given that, pursuant to Minn. Stat. § 14.61, and the Rules of Practice of the Public Utilities Commission and the Office of Administrative Hearings, exceptions to this Report, if any, by any party adversely affected must be filed within 20 days of the mailing date hereof with the Executive Secretary, Minnesota Public Utilities Commission, 350 Metro Square, 121 7th Place East, St. Paul, Minnesota 55101. Exceptions must be specific and stated and numbered separately. Proposed Findings of Fact, Conclusions and Order should be included, and copies thereof shall be served upon all parties. If desired, a reply to exceptions may be filed and served within ten days after the service of the exceptions to which reply is made. Oral argument before a majority of the Commission will be permitted to all parties adversely affected by the Administrative Law Judge's recommendation who request such argument. Such request must accompany the filed exceptions or reply, and an original and 15 copies of each document should be filed with the Commission.

The Minnesota Public Utilities Commission will make the final determination of the matter after the expiration of the period for filing exceptions as set forth above, or after oral argument, if such is requested and had in the matter.

Further notice is hereby given that the Commission may, at its own discretion, accept or reject the Administrative Law Judge's recommendation and that said recommendation has no legal effect unless expressly adopted by the Commission as its final order.

STATEMENT OF ISSUE

What is NSP's pre-merger electric retail revenue requirement in Minnesota?

Based upon all of the proceedings herein, the Administrative Law Judge makes the following:

FINDINGS OF FACT

Procedural Background

1. On or about May 1, 1995, Northern States Power Company and Wisconsin Energy Company (WEC) announced their intention to merge. The merged entity will be named Primergy Corporation (Primergy).

2. On August 4, 1995, NSP filed with the Commission its petition for approval of a merger with Wisconsin Energy Corporation in this matter. As part of its filing, NSP also requested Commission approval to acquire certain gas properties of NSP-Wisconsin, to defer accounting on its merger expenses, and to reduce retail electric rates by 1.5% across the board and freeze them for four years.[1]

3. On June 25, 1996, the Commission issued an Order Establishing Procedural Framework and Notice and Order for Hearing in this matter. The Commission determined that for a number of the issues needing resolution, a notice and comment process was sufficient. Five issues were referred for contested case hearings before the Office of Administrative Hearings. This Report concerns one such issue -- the pre-merger revenue requirement.

4. Twelve witnesses provided pre-filed and oral testimony on behalf of the parties in this segment of the case: Paul Pender (NSP), Jeffrey Robinson (NSP), David Grover (NSP), Curtis Nelson (OAG), Allen Krug (DPS), Dale Lusti (DPS), John Kundert (DPS), Elizabeth Donati (DPS), Sundra Bender (DPS), Eilon Amit (DPS), Jack Litzau (DPS), and Richard Lancaster (CP). The Administrative Law Judge also took official notice of the record developed in the two other contested case segments of the proceeding.

Test Year

5. The Commission's Procedural Order prescribed the use of a "1996 test year adjusted for known pre-merger changes in 1997."

6. The Company interprets the Commission's Order as requiring the use of calendar year 1996 as the test year, adjusted for "known and measurable changes" expected to occur in the period when the rates will become effective. Under this interpretation, the Company includes expenses for Network Transmission Service (NTS) credits and Project 2000 (computer software reprogramming) it knows will occur in 1997 and which, it contends, will not be set off by any increase in sales.

7. The DPS, with the support of the Office of the Attorney General, took the position that none of the 1997 expenses (NTS and Project 2000 are the only ones in contest) proposed by the Company for inclusion in the test year as "known pre-merger changes in 1997" are appropriate for inclusion in the test year because the company has not presented a fully-forecasted budget for 1997. As a corollary to this position, the DPS and/or OAG maintained that if NTS and Project 2000 qualify as "known pre-merger changes", then the Commission should recognize items of additional revenue that are not related to sales, such as payment(s) resulting from the settlement of certain litigation. The issues summarized in this and the preceding Finding are discussed further below.

Budgeting and Forecasting

8. NSP's budgeting and forecasting procedures were adequate and reliable for ratemaking purposes.

9. In the development of its test year, NSP adopted a three step process. Step 1 developed the 1996 base forecast revenue requirements; Step 2 adjusted the base revenue requirement in an attempt to make it representative of pre-merger conditions and to eliminate non-recurring items; and Step 3 attempted to adjust the 1996 data for certain significant known pre-merger changes in 1997.

10. The Company's unadjusted rate base used actual data through March 30, 1996, and budgeted data for the remainder of the 12-month period ending December 31, 1996. The Company's unadjusted income statement used actual data through June 30, 1996, and budgeted data for the remainder of the 12-month period ending December 31, 1996.

11. The Administrative Law Judge finds that NSP's three step process for determining its test year was a reasonable and appropriate approach and provides an appropriate starting point for determining NSP's pre-merger revenue requirement.

12. The Department's review of NSP's capital budgeting system in its most recent rate case, Docket No. E002/GR-92-1185, indicated that NSP's capital budgeting system provides data that can be relied upon for rate-case purposes. The Department reviewed the projected capital expenditures that NSP included in this proceeding, and performed a brief review of NSP's capital expenditure budget, including an on-site audit with the assistance of an NSP employee. During this review, DPS Witness Dale Lusti traced the development of NSP's 1996 rate base, which includes projected capital expenditures from April 1996 through December 1996. DPS Ex. 74 at 6.

13. Mr. Lusti also reviewed the historic accuracy of NSP's capital expenditure budgets, and briefly reviewed the 1994, 1995, and January-June 1996 budget deviations by business unit, function and category. Based on this review, and Mr. Lusti's extensive review in previous proceedings, the Department believes that NSP's capital expenditure budgeting system does provide reasonably reliable data for ratemaking purposes. Id.

14. The operating expense budget relates to the pre-merger revenue requirements in the following way. The Company's base year is calendar-year 1996. At the time when NSP was preparing this data, it had actual data only through June 30, 1996. Therefore, NSP used the operating expense budget to provide data for the remaining six months until the end of the base year (July 1996 through December 1996). Id. at 8.

15. The Department's review of NSP's operating expense budgeting system in Docket No. E002/GR-92-1185 indicated that NSP's system provides data that can be relied upon for rate-case purposes. In addition, the Department believes the level of budgeted operating expenses included in the unadjusted operating income is reasonable. Based on Mr. Lusti's brief review in this proceeding and his extensive review in previous proceedings, the Department believes that NSP's operating expense budgeting system provides reasonably reliable data for ratemaking purposes. Id.

Rate Base

16. In their initial briefs, NSP and the Department identified several areas of agreement regarding development of the Company's pre-merger revenue requirements. Areas of agreement include the level of jurisdictional average rate base under the Step-1, Step-2 and Step-3 scenarios, and several adjustments to the operating income statement under the Step-1 and Step-2 scenarios.

17. In the development of the Minnesota rate base for the test year, NSP included net utility plant measured at depreciated original cost and using the average of beginning and end of year balances. NSP included accumulated deferred taxes based on the average of beginning and end of year balances; made allocations to the Minnesota jurisdiction of rate base items that served the multi-jurisdictional utility; performed a comprehensive lead-lag study to determine cash working capital; determined materials and supplies and prepayments on the basis of 13 monthly balances ending December, 1995 and, for fuel inventory, ending December, 1996, and for all other items, actual data ending March, 1996 and forecast data for April through December, 1996; included construction work in progress with an allowance for funds used during construction credited to net income; and made adjustments to incorporate specific accounting items which impact the test year rate base.

18. NSP's initial calculation of the Minnesota jurisdictional rate base totaled $2,495,142,000.

19. DPS did not recommend any adjustments to NSP's Step 1 test year rate base, except adjustments to cash working capital to reflect its proposed adjustments to the operating income statement. OAG witness Nelson recommended one adjustment that

would affect slightly both the rate base and the operating income statement, relating to market based wholesale customers.

20. NSP's revised rebuttal (final) proposal for the test year Minnesota jurisdictional rate base, after recalculation of cash working capital requirements based on income statement adjustments, is $2,496,646,000. All parties recognize that this amount may be affected by recalculation of Cash Working Capital to reflect adjustments to the operating income statement adopted ultimately by the Commission.

21. NSP calculated its Cash Working Capital requirement by applying Lead/Lag study factors to its operating and maintenance (O&M) expenses. The Department reviewed the Lead/Lag factors that NSP used in this proceeding and recommends an adjustment to Cash Working Capital to reflect the Department's recommendation regarding test-year O&M expenses. As a result of the O&M expense adjustments described in the previous section of this brief, the Department adjusted Cash Working Capital by applying NSP's Lead/Lag study to the Department's adjustments to O&M expenses. DPS Ex. 74 at 15.

22. As a result of the Department's various adjustments, the Department recommends a step-1 jurisdictional average rate base of $2,494,946,000, and a final (Step 2) rate base of $2,496,515,000 a difference of $131,000 from NSP's final number.

23. If the Commission does not accept the ALJ's proposed revenue requirements in total, it will be necessary for the Commission staff to recalculate Cash Working Capital to incorporate the effect of the approved revenue requirements on income taxes.

Operating Income Statement -- Steps 1 and 2

24. In developing the operating income statement for Step 1, NSP employed the same basic methodology as was adopted by the Commission in NSP's last general rate case (E002/GR-92-185). Thus, expenses of like kind or nature, ordered to be excluded in the most recent general rate case, were excluded from this test year. Also, the same basic jurisdictional allocation methodology was utilized.

25. NSP departed from past Commission orders in only two respects.

- NSP proposed a "new and improved" method for allocating administrative and general expenses ("A&G") to the appropriate jurisdiction. This method is disputed by the DPS. See subsequent Findings.
- Because of significant changes in this class, NSP proposed to credit net revenues from its wholesale customers against the jurisdictional revenue requirement, instead of allocating costs to those customers, as had been the previous procedure. This methodology is disputed by the OAG. See subsequent Findings.

Intervenors DPS and OAG reviewed NSP's Step 1 filing, approved parts and proposed changes to other parts. The parties reached agreement on the following Step 1 issues:

a. <u>Sales Forecast</u> NSP developed a sales forecast which was adjusted for abnormal weather. This forecast (29,842,644 MWh), was reviewed and agreed to by DPS and is reliable.

b. <u>CIP/DSM Amortization Expenses</u>

DPS reviewed NSP's CIP and DSM amortization expenses ($49,899,000) and agreed they were consistent with expenses of like kind and nature as previously approved by the Commission.

c. <u>Economic Development Costs</u>

DPS reviewed NSP's economic development expense forecast, found that the costs developed by NSP in this proceeding were consistent with the Commission's order in NSP's most recent rate case and, consequently, determined that the level of such expenses for the test year ($268,000) was reasonable.

d. <u>Advertising Expenses</u>

The parties agreed that NSP's test year electric jurisdiction advertising expenses of $1,088,108 are reasonable and should be allowed.

e. <u>Electric Marketing</u>

The parties agreed that test year electric jurisdiction electric marketing expenses of $350,636 are reasonable and should be allowed.

f. <u>Organization Dues and Donations</u>

DPS reviewed NSP's organizational dues ($2,887,000) and charitable contributions ($2,080,000) forecast and found the test year amounts to be appropriate.

g. <u>Sales for Resale Correction</u>

In the development of the unadjusted 1996 forecast, NSP's sales for resale revenues for the first five months of actual data were inadvertently omitted, requiring an adjustment reducing Minnesota jurisdictional expenses by $3,832,000.

h. <u>Revenue Credit Correction</u>

In the development of the unadjusted 1996 forecast, NSP inadvertently included an amount as an increase to revenues when it should have been a decrease. NSP and DPS agreed to correct this error by increasing jurisdictional production expense by $900,000.

i. Normalization Adjustment for Le Sueur and Olivia.

NSP also agreed with the Department's recommended adjustment concerning the Le Sueur/Olivia wholesale revenue credit, which decreases Minnesota jurisdictional wholesale revenues by $1,657,000, decreases the Minnesota jurisdictional production expense by $467,000 and decreases the Minnesota jurisdictional transmission expense by $108,000.

j. Allocation of A&G

NSP proposed a new allocation method for allocating A&G to conform with FERC practice. No party opposes this change.

27. The Administrative Law Judge finds that the items and adjustments identified in the preceding paragraphs (26a. - 26j.)are supported by the record and should be allowed.

28. The only area of disagreement between NSP and the Department regarding the Step-1 operating income statement concerned two of the Department's recommended adjustments to the Company's method of allocating common corporate costs between its regulated and non-regulated operations.

DPS proposed an adjustment to NSP's regulated/non-regulated cost allocation methodology. The net effect of DPS's proposed adjustment is a decrease of $446,000 in the Company's Administrative and General expenses. NSP agreed with some of the specific adjustments but disagreed with the proposed changes in methodology.

29. The Administrative Law Judge finds that: (a) NSP's weighted allocation factor, that considers revenues, investment level and employee levels, is the most appropriate methodology for determining the allocation between regulated and non-regulated businesses and (b) regulatory fees are directly assessed to non-regulated businesses when affected by them and thus it would be inappropriate to include any portion of them in the corporate common cost pool for allocation to the non-regulated business.

30. The appropriate adjustments for regulated/non-regulated cost allocations are a reduction to test year electric jurisdiction operating and maintenance expenses of $35,000 for direct customer service costs related to Advantage Service and of $199,000 to reflect the change in the formula produced by using total Company revenues net of fuel and purchase gas cost.

DISCUSSION

The Department recommended an adjustment to the non-regulated corporate residual allocation. NSP allocated indirect joint and common costs between its regulated and nonregulated activities. The Company used a two-step process to allocate common administrative and general (A&G) corporate costs. First, once direct charges, cost-causation allocations and overhead rates have been developed and charged to nonregulated activities, NSP analyzed the remaining A&G costs at the task level to identify all allocable joint and common corporate costs. Second, a general allocator was developed using net investment, revenues (net of cost of goods), and employee levels. In developing this allocator, NSP calculated ratios of nonregulated net investment, revenues and employee levels to that of total company. Then NSP weighted the ratios as follows: net investment at 30 percent, revenues at 11 percent, and employee levels at 59 percent. The allocator was applied to the common corporate cost pool (determined in the first step) to calculate the allocation (corporate residual allocation) to the nonregulated businesses. Overheads were also applied to the corporate residual allocation. DPS Ex. 65 at 9-10.

The DPS disagrees with the Company's calculation of the general allocator dividing the common corporate cost pool among regulated and non-regulated operations. It believes the allocation to non-regulated operations should be reduced from 7.374% to 7.368%, and that revenues used in the calculation should be reduced by costs passed through to customers directly.

The Department also did not agree with the Company's use of employee levels and net investment in the development of the corporate residual allocator because the costs being allocated are common A&G costs related to activities of the corporate function. The Department does not believe there is any relationship between these activities and employee levels. NSP calculated the 59-percent weighting factor, which it applies to the employee factors, based on a ratio of Minnesota jurisdictional labor costs to Minnesota jurisdictional non-investment operating expenses. The DPS argues that this calculation implies that the Company used employee levels as a proxy for each operation's share of labor expenses. However, the employee levels used by NSP have not been adjusted for employee time cross-charged from one operation to the other. Id. at 14.

The Department believes a more appropriate ratio would be based on all operating and maintenance expenses net of passed-through cost of goods sold. Ms. Bender noted that in the first step of the corporate residual allocation process, the Company used a ratio of operating and maintenance expenses to allocate the majority of the common costs allocated to the common corporate cost pool. Id.

The Department recommended that the corporate residual allocator be based on the ratio of revenues, with the revenues for the regulated Minnesota Company adjusted for passed-through cost of goods as discussed above. The Department believes that the adjusted revenue ratio most closely resembles the computation of the general allocator described in the Commission's Orders in Docket No. G,E999/CI-90-1008. Since the Company has indicated that information on expenses net of passed-through cost of goods sold is not available for each operation for the period used in the test year, the Department believes that adjusted revenues are the most reasonable indicator of the common corporate A&G support each activity receives. Id. at 15-16.

The ALJ does not agree with the Department's proposals regarding the percentage of various tasks allocable to the common corporate cost pool and the calculation of the general allocator factors, which would decrease the test-year Step-1

Minnesota jurisdictional electric A & G expenses by approximately $446,000 (including applicable overhead).

Regarding the proposals by DPS witness Bender for an adjustment to the corporate residual allocation, NSP replies that the allocation involves separating common Administrative and General (A&G) corporate costs. NSP used a two step process by first identifying all joint and common corporate costs that were not directly assigned and, second, developing a general allocator and applying it to the common corporate cost pool to calculate the allocation to the non-regulated business. Bender recommended four changes, two of which were agreed to by NSP while the other two are contested. Ms. Bender's addition of 10% of regulatory fees in the common corporate cost pool, based upon the allocation of regulatory fees to non-regulated activities approved by the Commission in NSP's last Minnesota rate case, is disputed by the Company. NSP witness Robinson explained that NSP sends invoices for direct assessment of regulatory fees to its non-regulated businesses where those regulatory fees relate to affiliate interest filing and administrative service agreements which benefit the non-regulated company. The Company opposes any further allocation of regulatory expenses to the non-regulated businesses and the Administrative Law Judge agrees.

The Company agrees with Bender's recommendation that the revenues of the regulated Minnesota company be reduced in the calculation of the general allocator by passed-through fuel expenses and interchange revenues. The parties therefore agree with Bender's suggestion to use Minnesota company revenues, net of fuel and purchased gas, instead of total Minnesota company revenues, to calculate the allocator.

The Company disagrees with Ms. Bender's criticism of the three factor allocation method used by NSP, which considers revenues, investment and employee levels. Bender suggests that the relationship between the common A&G costs and investment levels is tenuous and there is no relationship with employee levels. The Administrative Law Judge disagrees.

NSP used a weighting method that considered all three factors in developing this allocator, whereby the level of revenue, investment and employees for each non-regulated business are weighed in to calculate an allocator reflecting the overall size of the businesses and the relationship of the business size to the size of the consolidated corporation. The Company filed this three factor method with the Public Utilities Commission in response to the Commission's Order in Docket G-E999/CI-90-1008, the generic cost allocation docket, and has applied this method to all jurisdictions since the filing. The Company maintains that this methodology provides a reasonable and comprehensive approach to the allocation of joint and common corporate costs to non-regulated businesses, and the Administrative Law Judge agrees. He is persuaded by the argument that Ms. Bender's method, which relies on a single allocator (level of revenues) is problematic.

The ALJ agrees that it does not necessarily follow that the corporate officers whose compensation make up the corporate common cost pool devote proportionately more time to the management of operations with higher revenue margin levels. It is noted that operations with declining revenue margins may receive increasing management attention. The ALJ is persuaded that using all three factors in the allocator provides greater balance and is a more reasonable measure of the way in which common A&G costs are actually used to benefit non-regulated businesses.

31. NSP proposed to credit revenues from its wholesale customers against the retail revenue requirement. Early in 1996, the basis for service to wholesale customers changed dramatically. At that time the last of NSP's traditional cost of service wholesale contracts expired and NSP was required to reduce its rates, in proposing new replacement contracts with these customers, in an attempt to meet competition from other suppliers. NSP obtained the largest contribution possible from its wholesale customers.

32. The OAG disagreed with the ratemaking treatment NSP has proposed for what it claims is the revenue shortfall generated by its market-based wholesale customers. Formerly, the rates for these customers were cost-based. Subsequently, in recognition of competitive markets, FERC authorized reliance on "market based" rates. In response to an OAG Information Request, the Company indicated that during 1995, the costs associated with providing that wholesale service exceeded the revenues by $673,000. Nelson Surrebuttal Testimony, OAG Ex. 26, Schedule 1, p. 2 of 17. In this docket, NSP proposed to "recover" this $673,000 from Minnesota retail ratepayers. OAG objected to NSP's new methodology, arguing that NSP should be required to allocate the full cost of serving the wholesale class. NSP maintains that the OAG's argument does not take into account changes in the market or the fact that the market based wholesale rates, that were necessary to retain any wholesale customers, do provide some contribution to NSP's embedded costs and thus benefit retail ratepayers.

33. The ALJ finds that this $673,000 should not be "recoverable" from Minnesota retail ratepayers for three reasons. First, it is not technically accurate to say that the Company has experienced a revenue shortfall with respect to its wholesale customers. The rates charged those customers are set by the market. Second, NSP's proposal would result in cross-subsidization of NSP's wholesale operations by retail ratepayers. Third, NSP has not demonstrated that retail ratepayers should bear the burden of costs incurred in the provision of wholesale service.

34. NSP made several Step 2 adjustments to the 1996 base forecast.

35. NSP made an adjustment to normalize weather using methodology that has been accepted for ratemaking purposes. The result of NSP's weather normalization was to remove $4,383,000 (net of fuel and purchased power costs) from electric revenues. No party opposed NSP's adjustment and it should be allowed. The Administrative Law Judge finds that NSP's electric revenues should be adjusted in the amount of $4,383,000 for weather normalization.

36. Shortly after the June 1996 forecast was completed, NSP revised its sales forecast for the remainder of the year necessitating an adjustment to reduce retail electric revenues by $3,517,000 for the Minnesota jurisdiction, with a related reduction in purchased energy of $706,000. No party opposed this adjustment and it should be allowed. The Administrative Law Judge finds that NSP's retail electric revenues should be reduced by $3,517,000 for the Minnesota jurisdiction, with a related reduction in purchased energy of $706,000.

37. In July of 1996 the Commission ordered changes to NSP's certified depreciation rates. (Doc. Nos. E,G002/D-96-160 and E,G002/D-95-1352). These orders were issued after the June, 1996 forecast. In order to properly reflect the newly certified depreciation rates, NSP reduced total depreciation expense for the Minnesota jurisdiction by $3,353,000. No party opposed this adjustment and it should be allowed. The Administrative Law Judge finds that NSP's depreciation rates are reasonable and appropriate for ratemaking purposes.

38. As the result of an arbitration award involving a dispute with Manitoba Hydro, NSP reversed a prior period credit adjustment for Manitoba Hydro demand charges, resulting in a $4,578,000 credit for the 1996 forecast year. Since this was a one time settlement and related to prior periods, NSP made an adjustment to eliminate it from the test year revenues. The adjustment had a Minnesota jurisdictional impact of $3,000,490. The Administrative Law Judge finds the adjustment of $3,000,490 appropriate.

39. NSP made an adjustment to reduce test year expenses by $3,624,000 to reflect the end of SFAS 106 amortization. This cost would not be an ongoing cost representative of 1997. No party objected to this treatment. The Administrative Law Judge finds that a decrease in test year expenses of $3,624,000 is appropriate.

40. In 1996 NSP changed its accounting method for NEIL Nuclear Insurance premium refunds from a "cash received" to an "accrual" method, meaning that both the cash received for 1995 and the accrual for 1996 were included as 1996 business. NSP proposed an adjustment so that only one refund amount would be in the test year. This adjustment reduced revenues by $2,484,000 at the Minnesota electric jurisdictional level. No party disagreed. The Administrative Law Judge finds that an increase in test year expenses of $2,484,000 for nuclear insurance is appropriate.

41. The only area of disagreement between NSP and the Department regarding the Step-2 operating income statement concerned the Department's recommended adjustment to increase the Company's Minnesota jurisdictional electric labor costs by $2,848,000 to reflect the cost of 69 employee reductions which NSP claimed to be merger-related. In addition, the Department contested both of NSP's Step-3 adjustments (concerning Project 2000 costs and NTS credits) as well as the Company's recommended return on equity. The Step 3 disputes are discussed in detail in subsequent Findings.

42. For purposes of the pre-merger revenue requirement, NSP maintains it needed to reflect the number of employees that would have produced labor expense for the test year if no merger had been announced. NSP concluded that 69 employees, who had left NSP's employment during the test year, were merger related in the sense that these positions would have been filled by new employees if there was to be no merger. NSP proposed an adjustment to add labor expense by multiplying the number of employee reductions related to the merger times the average loaded labor rate times the number of months that they were absent from the 1996 forecast. The adjustment resulted in an increase in Minnesota jurisdictional electric "loaded" labor costs of $2,848,000.

43. DPS and OAG challenged NSP's claim that the expenses associated with the 69 employees should be considered merger related. DPS and OAG asserted the positions either should have been filled or were not necessary.

44. The Department disagreed with this adjustment, arguing that NSP can achieve significant productivity gains (cost reductions) even without the merger. DPS Initial Brief at 52-53. In other words, NSP's adjustment to add labor expenses to the test-year is not justified simply by asserting that the employee reductions were merger related when, in fact, NSP's own pre-merger productivity goals could have led to the elimination of at least 69 employees. Id. at 53.

45. Department witness Edward Bodmer testified that, given NSP's goal of achieving productivity gains at the top quartile of comparable companies, NSP has the opportunity to achieve more than $10 million in annual savings absent the merger, in addition to the $9.6 million of pre-merger initiatives identified by NSP witness Flaherty. DPS Ex. 75 at 4-5. Based on Mr. Bodmer's analysis, Mr. Lusti concluded that it is not appropriate to accept NSP's adjustment for merger-related employees. Id. The $10 million in potential annual productivity savings translates to between $4 million and $4.5 million on a Minnesota jurisdiction basis, which is more than the $2.8 million adjustment proposed by NSP for the 69 position eliminations. Tr. Vol. 5 at 149. In other words, NSP could have eliminated far more than 69 positions on a pre-merger basis just by achieving its own pre-merger productivity goal.

46. The OAG provided further support for the Department's position on this issue through its reference to the Commission's recognition of the industry-wide push for efficiencies by electric utilities in the face of increasing competition. OAG Initial Brief at 12. Given these cost-cutting pressures, and NSP's ability to realize additional productivity gains on a pre-merger basis, beyond the 69 eliminated positions, the DPS and OAG maintain that there is simply no justification for NSP's assertion that it would have filled these 69 vacant positions (or could not reduce a similar number of other positions) absent the merger.

47. The 69 positions were necessary for the provision of reliable service, absent a proposed merger. The 69 positions do not represent excessive or imprudent costs since NSP's A&G costs per megawatt hour are below the industry average and no imprudence has been shown. The cost of these 69 positions should be included in NSP's pre-merger operating expenses.

The Administrative Law Judge finds that an increase in Minnesota jurisdictional electric loaded labor costs of $2,848,000 to reflect the 69 merger-related employees is appropriate.

DISCUSSION

The Department recognizes that NSP suggested that the top-quartile productivity standard used in Mr. Bodmer's productivity study should not be used "as a benchmark for recoverability of expenses." NSP Initial Brief at 21. However, it must be remembered that the Department is not using this study as a benchmark for recoverability of expenses that were actually incurred by NSP in the 1996 test-year; the Department is using the productivity study to challenge NSP's inclusion of $2,848,000 of "phantom" labor costs in this case, costs which NSP simply did not incur. It argues also that NSP has not demonstrated that it would have incurred these labor costs absent the merger.

The DPS argues that the top-quartile productivity target was not Mr. Bodmer's invention, but was a benchmark adopted by NSP to assess pre-merger and post-merger staffing levels. NSP Ex. 37 at 19.

Mr. Bodmer's productivity analysis is offered to demonstrate that NSP is below top-quartile performance in productivity. DPS Ex. 75 at 4-5. Even the 69 position eliminations would not bring NSP up to its productivity target. Tr. Vol. 5 at 149. Therefore, the DPS argues that NSP is not justified in asserting that it would have filled the 69 vacant positions (or could not reduce a similar number of other positions) absent the merger.

The OAG supports the position of the DPS regarding the 69 employees NSP did not replace during 1996. The OAG emphasizes that the fact that NSP operated effectively during the test year without those employees supports finding that the expenses should be removed from the test year. It notes also that the PUC highlighted the fact that Wisconsin Energy has "down-sized" by 1000 employees prior to the merger in its Order Establishing Procedural Framework, page 12 (6/25/96). The OAG argues that these facts all support a finding that NSP has underestimated the savings reasonably achievable from pre-merger initiatives, so it is appropriate to exclude labor expenses for the 69 employees never replaced.

The OAG points out also that if the ALJ accepts NSP's test year inclusion of these expenses (which he has above), the Company still estimates that the 69 positions would be eliminated in 1997 due to merger-related efficiencies. Therefore, the $2,848,000 in expenses associated with the positions should be included in first year merger-related savings.

The DPS and OAG argue that NSP's Step 2 adjustment for merger-related employees is not appropriate, given the amount of expenses that could be saved through normal productivity gains prior to the merger and the fact that the employees "either were laid off or not replaced", which is inconsistent with their being "essential" employees. The record shows that the 69 positions were lost due to attrition, and the Company did not replace them because at least that many employees would lose their jobs due to the merger. Rather than hire new employees who would simply have to be laid off, the Company made the decision to operate in the pre-merger interim period of time without filling the 69 positions. The ALJ views this as an ordinary, reasonable business decision and does not believe the Company should be punished for not filling positions that would have existed but for the merger. He sees no bad faith by the Company regarding its representation that the 69 positions would still exist if NSP had not planned to merge with WEC.

With respect to DPS witness Lusti's reliance on Mr. Bodmer's testimony, the Administrative Law Judge is persuaded that the reliance is misplaced. It is clear that Mr. Flaherty did not set any "goal" for NSP. Indeed he is not even employed by the Company, but is a retained consultant. Furthermore, there is no evidence that the Company has itself, internally, established a goal of reaching the top quartile in the measurements cited by Mr. Bodmer. Every utility has a different mix of A&G costs and they are not necessarily directly comparable, so any projection to a "top quartile" is necessarily arbitrary. For example, as a nuclear utility, NSP must purchase nuclear liability insurance, which is included in its total corporate A&G costs. That insurance is not required of other utilities to whom NSP was compared.

It is noted that neither Mr. Lusti nor Mr. Bodmer cited any specific A&G cost that was unreasonably high or imprudent for the purpose of setting customer rates. Lusti testified that he had not found any of NSP's A&G costs to be imprudent (T.5, pp. 143-145).

An examination of Mr. Bodmer's filed testimony (Ex. 40) shows that he acknowledged NSP's "performing at higher productivity levels than the industry average" (Ex. 40, p. 38).

As to why the employees were not replaced, NSP witness Robinson notes that NSP expected the merger to be approved in a shorter time frame and therefore planned to maximize the use of normal employee retirements and attrition to achieve workforce reductions, allowing the Company to maximize merger-related savings while keeping severance costs associated with merger-related reductions to a minimum. The Company should not be penalized for establishing such a "transition" mode of operation under which they did not refill the vacated positions until the merger was complete, at which point the positions will be eliminated in any event. The Administrative Law Judge is persuaded that the "transition" mode taken on by the Company during the interim prior to the merger does not represent the level of workload NSP would have continued with on an ongoing basis, absent the merger.

Westinghouse Settlement

*** * * Proprietary * * ***

Findings 48-54 and the Discussion following them are Proprietary.

*** * * End of Proprietary * * ***

Step 3

55. NSP maintains that the primary purpose for the Step 3 adjustments is to recognize that 1997 will be the first year in which the merger would be effective and thus adjustments for known changes in 1997 are necessary to provide a proper pre-merger foundation from which to measure merger savings. NSP limited the number of 1997 adjustments to only those that are known, significant and not directly related to changing sales levels. By limiting itself to these adjustments, NSP provided an adjusted 1996 test year which approximates a 1997 year on a pre-merger basis. While NSP considered several adjustments, it made only two.

56. DPS and OAG objected to the Step 3 changes proposed by NSP. They argued that no changes should be allowed in the absence of a fully projected 1997 test year.

The Administrative Law Judge disagrees. NSP was not ordered to construct a fully forecasted future test year. It was ordered to provide a historical test year adjusted for known changes. Consequently, it is appropriate to adjust the 1996 results for known and measurable changes in 1997.

Network Transmission Service (NTS)

57. NTS became effective in 1996 and will continue through 1997. It allows the transmission service customer to fully integrate load and resources on an instantaneous basis, in a manner similar to the transmission provider's integration of its own load and resources. NTS customers pay a load ratio share of the total network costs, and receive a credit for facilities they own which are integrated with the network. Because three of the NTS customers have investment in integrated transmission facilities which exceeds their load ratio share of the total network cost, this results in payments to them of facilities credits, forecasted at $19 million for 1997. After subtracting the $3 million of NTS costs already included in the June, 1996 forecast for the last two months of 1996, the net 1997 adjustment for NTS was proposed at $16 million on a total system basis, and $12,198,000 for the Minnesota electric retail jurisdiction.

58. In its review of this adjustment, DPS discovered, and NSP agreed, that there was an inadvertent omission of NTS related revenues totaling $1,092,000 for the Minnesota electric jurisdiction. This correction reduced NSP's Step 3 adjustment to $11,106,000.

59. DPS and OAG argue that NTS is not a known and measurable change in 1997 because of alleged uncertainty that NTS Service will be in existence. The Administrative Law Judge disagrees. NTS Service has been in existence since November of 1996. If the NTS credits in 1996 were annualized, the amounts would be at the same level as the proposed adjustments for 1997. The only uncertainty concerning the continuation of NTS is whether it will be replaced, in whole or in part, after December 31, 1997, by Capacity Reservation Tariffs ("CRT"). Such uncertainty does not affect 1997 and possible changes in 1998 or after are not relevant to this proceeding.

60. NSP's updated calculation of the 1997 NTS credits would increase the NTS expense for the Minnesota electric jurisdiction by $2.9 million. Such an increase does not make the NTS credit uncertain for 1997, but instead provides confidence that the adjustment proposed by NSP is conservative.

61. The Administrative Law Judge finds that an adjustment to add $11,106,000 for NTS expense is appropriate as a known and measurable change from 1996.

Project 2000

62. NSP's second 1997 adjustment relates to the cost to identify and modify all computer applications and programs that will be affected in the year 2000 by the present computer software logic which uses the two digit calendar year as a form of counter. NSP expects to incur costs of $784,000 in 1996 and $5 million in 1997 on this project. NSP proposed inclusion of an additional $4,216,000 as a 1997 adjustment to operating expenses, with an increase in the Minnesota jurisdiction electric operating expenses of $3,495,000.

63. DPS proposed to reduce this amount by $94,000 to reflect an allocation of this adjustment to non-regulated businesses, resulting in a net adjustment of $3,401,000. NSP agreed.

64. The Administrative Law Judge finds that the adjustment to add $3,401,000 in Project 2000 expense is appropriate as a known and measurable change from 1996.

65. NSP has also demonstrated that the four year total cost of Project 2000 is estimated to be $20 million, which is consistent with the proposed test year level of $5,000,000 on a total Company basis. NSP has also demonstrated that the pattern of costs over this period will fluctuate. To provide a proper matching of revenues and expenses, NSP has proposed to utilize deferred accounting to amortize the test year expense level ratably over a four year period.

66. The Administrative Law Judge finds that the use of deferred accounting and a four year amortization of test year Project 2000 costs is appropriate. It is appropriate to recognize $5,000,000 in Project 2000 expenses during the test year.

<u>Other 1997 Expenses</u>

67. NSP considered other 1997 items. These included the general wage increase which will occur in 1997, pre-merger labor reduction initiatives and greater than normal overtime in 1996. As to the wage increase, NSP forecasts a 4% increase for 1997, resulting in labor cost increases of about $12.7 million. While an adjustment would normally be made for this increase in labor costs, the other two items mentioned above offset the increase. First, NSP anticipates a net labor reduction of about $7.9 million from pre-merger cost savings initiatives. Second, NSP had greater than normal overtime in the first part of 1996 and the normalization of that overtime produces a decrease in labor of $4.6 million. The net of these three items is $0.2 million. NSP considers all these items to be appropriate Step 3 adjustments. However, due to their immaterial net impact, no adjustment was proposed.

68. Another item considered was the LS Power purchase power contract, which will begin in May of 1997 and obligates NSP to expend $16 million in capacity charges in 1997. However, this increased expense due to the LS Power contract is considered by the Company to be growth related and could be offset by increased revenues from 1997 sales. Thus, NSP made no adjustment.

69. The Administrative Law Judge finds that the record supports NSP's decision not to include adjustments for the items mentioned in the two preceding Findings.

70. DPS and OAG raised concern over additional items for which NSP did not make a Step 3 Adjustment. Both parties raised concerns about the recently-approved Southern Minnesota Municipal Power Association (SMMPA) settlement and OAG raises concern about a recent court decision involving property taxes for the Prairie Island generating unit. The ALJ takes official notice of the December 19, 1996 Settlement Agreement resolving the property tax dispute, as detailed in the next <u>Discussion</u> segment.

71. Subsequent to the filing of the testimony in this segment of the contested case, the SMMPA settlement was approved by the FERC. NSP has filed with the MPUC a request for deferred accounting, to amortize the $10 million refund it will receive from SMMPA over the four year rate freeze, or $2.5 million per year. NSP proposes that no revenue requirement adjustment be made for the SMMPA refund and instead that the refund be offset by the understated (by $2.9 million) 1997 NTS expense.

72. In its initial brief, the Department explained the inequity of NSP's proposal to recover 1997 costs related to Project 2000 and NTS Credits without recognizing the potential settlement award the Company expected to receive from SMMPA. DPS Initial

Brief at 61. The Company explained that it limited its 1997 known changes to Project 2000 and the NTS Credits because it "intentionally chose to make adjustment only for items that were not related to, and would not be offset by, growth in sales." NSP Initial Brief at 5. NSP's SMMPA settlement proceeds are not related to or offset by a growth in sales, yet NSP did not include an adjustment for this item which favors the Company's ratepayers. The Company asserted that it did not include the SMMPA settlement proceeds in the revenue requirement because it was not certain when and if FERC would approve the settlement. Tr. Vol. 4 at 82. However, even when the certainty of receiving the settlement proceeds was no longer in doubt, the Department notes that NSP still did not propose to include the SMMPA settlement proceeds as an offset to the Project 2000 or NTS Credit costs it has included in this case. NSP Initial Brief at 37.

73. In addition, as the OAG pointed out, NSP has failed to submit evidence regarding a property tax assessment decision that is favorable to ratepayers (i.e., a cost reduction for NSP). OAG Initial Brief at 8. The DPS maintains that these examples demonstrate that NSP has not made a good faith effort to propose adjustments for known 1997 changes that would benefit ratepayers.

74. It is not appropriate to include SMMPA settlement payments or personal property tax refund or settlement payments (discussed below) in test year revenues.

DISCUSSION

The OAG and DPS argue that NSP's proposed adjustments for Network Transmission Service and Project 2000 are too uncertain to include and represent piecemeal ratemaking. They maintain that the Company failed to demonstrate that it took all reasonable actions to identify other adjustments that would decrease, rather than increase, the Company's revenue requirement, and that several items that arose during the hearing illustrate this point.

The first such item is NSP's settlement agreement with the Southern Minnesota Municipal Power Agency (SMMPA). That agreement, dated June 1, 1996 and filed with the Federal Energy Regulatory Commission (FERC) on September 26, 1996, calls for SMMPA to pay NSP $10,000,000 in settlement of disputes related to past claims regarding the NSP - SMMPA Shared Transmission System Agreement and the NSP - SMMPA Outlet Agreement. NSP did not include the settlement as a 1996 or 1997 adjustment to the test year because, as of the date of the hearing, it had not been approved formally by FERC. Subsequent to the hearing, FERC approved the settlement (on December 18, 1996). Since the certainty of the SMMPA settlement payment cannot be disputed at this point, the agencies argue that it should be recognized as additional revenue/income in this proceeding.

In response, NSP makes a further argument against amortizing $2.5 million of the SMMPA settlement payment in the test year. It argues that an additional $3.8 million in NTS payments, not accounted for in the $11,106,000 adjustment discussed in the Findings above, be used as an offset to the SMMPA refund.

The additional $3.8 million expense for NTS facilities credits that the Company proposes be applied as an offset to the SMMPA settlement revenues is based upon updated financial information provided by NTS customer Dairyland Power Cooperative (Dairyland). NSP proposed not to reflect that additional amount of expense in its final revenue requirement for the test year, proposing instead that it be used to offset any additions to revenue that might arise in the final calculation of a test year revenue requirement. Since additional NTS credits offset fully the proposed amortized portion of the SMMPA settlement refund, the Company argues that no adjustment to the revenue requirement need be made, even if the SMMPA refund is imputed into the test year. The Administrative Law Judge agrees.

The OAG notes that a second item benefiting ratepayers which NSP did not include as a Step 3 adjustment is a decision on October 17, 1996 of the Ramsey County District Court (Docket No. 6662). The decision reduces the Company's personal property tax assessment with respect to pollution control equipment installed at its nuclear plants at Prairie Island and Monticello.

On December 19, 1996, NSP and several other parties executed a settlement agreement resolving that personal property tax dispute. The OAG urges that the Administrative Law Judge take official notice of this public document, and he has done that. Pursuant to the Settlement Agreement, NSP will receive an annual tax exemption valued at approximately $4,145,370, which is to remain in effect "unless reduction or revocation of the exemptions is required by the Minnesota Legislature". The agreement calls also for NSP to remit to various parties payments in 1997 totaling $5,051,416 and in 1998 totaling $906,042. The 1997 and 1998 payments are one-time events. The OAG emphasizes that over a period of the four year freeze proposed by the Company, NSP's personal property taxes will decline approximately $16,568,000, while the Company makes settlement payments of just under $6 million. The Attorney General stops short of recommending that NSP must include this settlement recovery as an adjustment for revenue requirement purposes. The OAG argues that while it may be possible to create revenue adjustments for these items, similar to NSP's proposed NTS and Project 2000 adjustments, the record does not contain evidence sufficient to give the ALJ or the Commission confidence that this would establish a sound test year requirement for NSP, so it is improper to include only the two expense items advanced by the Company.

The Administrative Law Judge has decided against including the effects of the settlement agreements noted here in determining the revenue requirement for the purposes of the test year in this proceeding. The SMMPA amortization is offset by greater-than-claimed NTS expenses, and the tax savings should be handled as a possible freeze exemption that need not be recognized in the test year.

The Department advances the argument that it is inappropriate to recognize NSP's proposed adjustments for Project 2000 and NTS expenses because the Commission has expressed that a utility must have "compelling" reasons to justify the recovery of out-of-test-year expenses. The Department cites the "general rule" in this area, as follows:

> The "known and measurable" exception that the Company relies on is not automatic, as the Company suggests.

In a 1988 Order, the Commission stated its reasons for disallowing a test-year adjustment for post-test year changes: As a general rule the Commission is reluctant to adjust revenue requirements to reflect changes, certain or not, unless there is a compelling reason to do so. (Emphasis supplied).

NSP, Docket No. E 002/GR92-1195, (Order 9/29/93, at 49), quoting from PUC Decision in Minnesota Power's 1987 Rate Case.

The Department maintains that NSP has not satisfied the standard expressed above. It contends that NSP must go beyond simply demonstrating that it will incur the expenses at issue.

The Department cites NSP's last electric rate case further, to note the Commission's reluctance to recognize out-of-test-year adjustments, based on the fact that under the test year method rates are set on an assumption that changes in a facility's financial status during the test year will be roughly symmetrical -- some favoring the Company, others not. To not adjust for either type of change maintains such symmetry and maintains the integrity of the test year process. When a record does not identify all known and measurable changes to allow such equitable adjustments, the Department maintains (and argues that it is Commission precedent) that the best course is to maintain the test year boundaries intact. In this case, because NSP has not identified all known and measurable changes to allow equitable adjustments, the DPS argues that no such adjustments should be allowed.

The Administrative Law Judge does not agree. He is persuaded that the Company has acted in good faith and to the best of its ability to identify all known changes that are not affected by trends in the sale of electricity. He is persuaded that these are the type of changes the Commission had in mind when it allowed the Company to present a pre-merger revenue requirement, based on a 1996 test year adjusted for "known pre-merger changes in 1997". For this basic reason, it is appropriate to allow recognition and adjustment of the revenue requirement for the purposes of this proceeding to recognize 1997 expenses related to Project 2000 and NTS Credits identified and asked for by the Company. He has considered the argument that selectively adjusting 1996 test-year revenue requirements for some specific changes to occur in 1997 is inappropriate because it is difficult to identify adjustments that are so unusual that either (1) a similar item did not occur within the base data or (2) an offsetting item will not occur as a direct result of the unusual item. He is persuaded that the Project 2000 and NTS Credits items do not fit within such a test.

The Department argues that its review of NSP's budgeting system has uncovered that new projects can be considered after a budget has been established only if a previously approved budget is delayed -- NSP uses the term "Substitution Project" to identify such items. Using Project 2000 adjustments as an example, the Department argues that it is possible (or probable) that a project of similar cost may have to be either canceled or deferred as a result of Project 2000. In this connection, the Administrative Law Judge notes NSP's argument that the analogy of Project 2000 to the term "Substitution Project" is inappropriate because such substitutions pertain only to capital projects, and Project 2000 is an expense item. The DPS urges the Judge to look beyond such semantics and recognize that the Company could choose to drop an expense item, such as annual tree-trimming, if "recovery" for Project 2000 or NTS payments is denied. He has, and is persuaded the expenses in question are "known and measurable" for 1997 and are not offset by related gains in revenue -- which the ALJ believes to be the appropriate inquiry.

Regarding the NTS Credits expense adjustment, the Department urges that a preferred treatment of this adjustment is to reject it, then allow NSP to refile its request once the allocation of transmission expenses is more certain after the Federal Energy Regulatory Commission decides on the many proposals and policies that could affect cost allocations and rates for transmission service in the Upper Midwest. Because the allocation of transmission costs in the future is uncertain, given present uncertainty over how the Primergy Independent System Operator (ISO) or any larger ISO including Primergy, and FERC Order No. 888 will dovetail, the Department maintains the Commission should base its decisions in this proceeding on sound financial information. This argument ignores the fact that the 1997 obligation of NSP to pay NTS credits in an amount greater than that it asks for recognition in the test year is a certainty. The Company's argument in this regard is supported by credible testimony filed on behalf of Cooperative Power.

<u>Alternate Step 3 (DPS)</u>

75. In the event that the Commission believes that Step-3 adjustments should be considered in the development of NSP's pre-merger revenue requirements, the Department offered its review of NSP's specific adjustments.

76. The Company started with its Step-2 normalized data, then adjusted this data for the following two items: (1) the NTS Agreement; and (2) Project 2000. In the event that the Commission determines that NSP's Step-3 adjustments should be considered in determining NSP's pre-merger revenue requirements in this proceeding, the Department has included them in its calculations. DPS Ex. 74 at 27. These adjustments are included in Appendix C at 8.1, column (b).

77. In the event the Commission decides to allow adjustments to 1996 test-year revenue requirements for 1997 Project 2000 expenses, the Department did not agree with NSP's proposed adjustment for 1997 Project 2000 expenditures. The Company failed to allocate any portion of these expenses to nonregulated activities. Approximately $104,000 of the $3,495,000 adjustment calculated by NSP is allocable to nonregulated activities. <u>See</u> DPS Ex. 65 at (SLB-4). Therefore, if the Commission decides to allow NSP to include estimated 1997 Project 2000 expenses in test-year operating expenses, the Department recommended that the amount be limited to $3,391,000.

78. The Department adjusted its Alternate Step-3 recommendation further by recognizing that if the Commission decides to approve an adjustment for the LS power expenses, then NSP's calculation should be used, and by recommending its own calculation to adjust test year income taxes by $29,000 (a decrease) for interest synchronization, an adjustment that results from the application of interest synchronization to the Department's various alternate step-3 adjustments. As a result of the Department's various adjustments, the Department's alternate step-3 test year operating income is $216,954,000.

79. As a result of the Department's various adjustments, the Department recommended an Alternate Step-3 jurisdictional average rate base of $2,497,319,000.

Rate of Return

80. NSP requested an overall rate of return of 9.01 percent based upon a return on equity of 11.47 percent and a capital structure consisting of 48.38 percent common equity, 39.76 percent long-term debt, 5.30 percent short-term debt, and 6.56 percent preferred stock; with 1996 average costs of 7.08, 5.80 and 5.14 percent for long and short-term debt and preferred stock, respectively. NSP Ex. 45 at PEP-1, Schedule 2, p. 1 of 2. The Department recommended an overall rate of return of 8.55 percent based on a return on equity of 10.49 percent. DPS Ex. 67 at 41. Neither the Department nor any other party filed testimony challenging NSP's proposed costs of debt and preferred stock and capital structure.

81. The Commission is obligated to set rates which are just and reasonable. Minn. Stat. § 216B.03. The determination of reasonableness involves a balancing of consumer and utility interests; the Commission must insure that NSP's authorized rate of return is set at a level which properly balances investor interests and consumer interests to the extent that NSP will not earn excess profits.

82. The United States Supreme Court has defined the proper regulatory balance between the interests of investors and ratepayers, in the Bluefield and Hope cases. It held in Bluefield Waterworks & Improvement Co. v. Public Service Commission of West Virginia, 262 U.S. 679 (1923), that a utility's return must be reasonably sufficient to assure financial soundness and provide the utility adequate means to raise capital. The Court concluded that a utility had no right to large profits similar to those realized in speculative ventures, but that the utility's return:

> [s]hould be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.

Bluefield, 262 U.S. at 693.

83. In Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591 (1940), the Court reaffirmed and refined the Bluefield principles. The Hope Court reiterated the investor requirement for a return sufficient to cover operating expenses, including services on debt and dividends on stock and to assure confidence in the utility's ability to maintain credit and attract capital. The Court added that a just and reasonable return should be similar to returns on investments in other businesses having corresponding risk. Federal Power Commission v. Hope, 320 U.S. at 603.

84. In addition, the Court has acknowledged that regulation must attempt to strike an equitable balance between investors and ratepayers. In Covington and Lexington Turnpike Road Co. v. Sanford, 164 U.S. 578 (1896), the Supreme Court recognized:

> [S]tockholders are not the only persons whose rights or interests are to be considered. The rights of the public are not to be ignored . . .. The public cannot properly be subjected to unreasonable rates in order simply that stockholders may earn dividends.

Covington, 164 U.S. at 596.

In Federal Power Commission v. Natural Gas Pipeline Company of America, 315 U.S. 575, 62 S.Ct. 736 (1942), this point was reemphasized:

> The consumer interest cannot be disregarded in determining what is a "just and reasonable" rate. Conceivably, a return to the company of the cost of service might not be "just and reasonable" to the public.

Id., S.Ct. at 753 (Clark, Concurring).

85. In sum, the Commission is obligated to balance the competing interests of NSP investors and ratepayers in assessing the reasonableness of NSP's proposed rates. The goal of regulation is met when rates are set at a level that allows the utility to earn a return sufficient to meet the Bluefield and Hope standards. The authorized rate of return must be commensurate with the risks of the enterprise. No purpose is served by allowing a return which is higher than required by NSP's investors. An excessive return would merely confer windfall gains on investors, while imposing unnecessary burdens on ratepayers. The Commission's obligation to set a fair return does not extend to guaranteeing that the authorized return will be earned. A utility is granted only the opportunity to earn its allowed return, not a guarantee.

86. A fair rate of return is, by definition, that rate which, when multiplied by the rate base, will give the utility a fair return on its total investment. The sum of a utility's fair return and operating expenses equals the utility's total revenue requirement. In a competitive environment, prices (rates) and operating incomes (returns) are determined by the free interaction of market forces, such as supply and demand. These market forces ensure, under certain conditions, that an optimum level and mix of various goods and services are produced. DPS Ex. 67 at 2.

87. But in the regulated utility industry, the role normally assumed by competition is assumed by regulatory agencies, which must ensure that utilities provide an appropriate supply of satisfactory services at reasonable rates. To provide these services the utility must be able to compete for necessary funds in the capital markets. To attract these funds the utility must earn enough to offer competitive returns to investors. Thus, a fair return is one that enables the utility to attract sufficient capital. Id.

88. No party disagreed with any of the components of the total cost of capital computation with the sole exception of the appropriate return on common equity. NSP witness Mr. Pender recommended continuing to use the 11.47% approved in NSP's last rate case. Dr. Amit for the DPS recommended 10.51%.

89. The return on equity used for this segment of the merger case should be determined on the same basis that it would be in a normal rate case. Neither of the witnesses made any adjustments or allowances associated with the special risks that would be associated with a rate freeze or the potential non-attainment of projected merger savings. The recommendations contained in this report make no such special adjustment. The Commission may consider the impact of these and other merger-specific factors in its deliberation of the entire merger filing.

90. The 11.47% ROE recommended by Mr. Pender was based on his review of risk premium (RP), capital asset pricing model (CAPM) and modified discounted cash flow (DCF) studies and returns on equity which have been granted in other rate proceedings in the last two years.

91. The 10.51% ROE recommended by Dr. Amit was based on the results of an NSP-specific DCF study, with a hybrid CAPM/DCF study used as a check for reasonableness. Dr. Amit also performed DCF studies for comparable groups of electric and combination utilities, also for the purpose of checking the NSP - specific results.

92. Both witnesses recognize that the electric utility industry is in the midst of unprecedented change, and the possibility of restructuring and retail competition make it more difficult than in the past to estimate reliably the current cost of equity. This was particularly evident in the discussion of the appropriate dividend growth rate to be used in the DCF studies. For instance, Dr. Amit testified that historical growth rates were not reliable indicators of investor expectations about the future, so he relied upon published growth projections for earnings and book value (though not 5-year projections for dividends).

93. Dr. Amit recommended an adjustment for issuance costs of 13 basis points. Mr. Pender recommended a similar adjustment, applicable to all of his studies, of 15 basis points.

94. Like Dr. Amit, Mr. Pender initially considered various DCF calculations of cost of equity. Unlike Dr. Amit, he did not find the results acceptable, but found all of the results suspect at this time, since the range of potential results was very large and some of the results provided little or no premium above bond or Treasury bill interest rates to reflect the higher risks associated with an equity investment.

95. Mr. Pender, however, performed a modified DCF study which, using Dr. Amit's NSP data and factoring in the potentially higher future dividend growth attributable to restructuring and retail competition, indicated a cost of equity for NSP of 11.7%.

96. NSP argues that as a result of the uncertainty of change in the industry, the unaccountably and unacceptably low results of the DCF studies, and the widely varying results of DCF studies which are contrary to risk differentials between NSP and supposedly comparable groups of utilities, Mr. Pender and NSP believe it is not reasonable to place primary reliance on DCF-based estimates of the cost of equity for NSP in this case.

97. The average of returns allowed in rate decisions rendered in 1995 was 11.7%, and the average of returns allowed in the first three quarters of 1996 was 11.3%. The California PUC, using DCF, CAPM and RP calculations, has set ROEs for the major

utilities in that state at 11.6% for rates in effect in 1997, the same rate used in 1996. For rates to be in effect in 1997 in Wisconsin, NSP(W)'s allowed return is 11.3% and WEC's allowed return is 11.8%.

98. Department witness Dr. Amit used the following economic guidelines, as set forth in the Bluefield and Hope cases, to determine a fair rate of return on common equity capital for NSP-Electric:

* The rate of return should be sufficient to enable the regulated company to maintain its credit rating and financial integrity.

* The rate of return should be sufficient to enable the utility to attract capital.

* The rate of return should be commensurate with returns being earned on other investments having equivalent risks.

Id. at 2-3.

99. The cost of equity capital to NSP-Electric is the rate of return that NSP-Electric must pay to investors to induce them to invest in the regulated company. To estimate this cost Dr. Amit used a market-oriented approach and relied on the concept of "opportunity costs." Investors are faced with many investment opportunities in the financial markets. To attract investors, NSP-Electric must pay a return similar to the return that investors expect to earn on investments of comparable risk. This rate of return is the cost of equity capital to NSP-Electric. When investors buy the common stock of a utility, they acquire the right to share any dividends that the company may declare in the future. The prospect of these dividends serves as an inducement to investors. Id.

100. A potential investor in common equity capital forms certain expectations about future dividends, based on the company's past and current performance, the company's prospects for future growth, and investors' perceptions of the current and future economic environment. Expected dividends play a key role in estimating the cost of equity capital. The expected dividend divided by the purchase price of the stock (the expected dividend yield) is a critical component of the cost of common equity capital. The investor in common stock expects to receive a flow of future dividends. Economic theory postulates that the price of the stock in the present period will equal the present value of all the expected future dividends discounted by the appropriate rate of return. If annual dividends grow at a constant rate over an infinite period, we can estimate the required rate of return on common equity capital in the following way:

The expected (required) rate of return on equity = the expected dividend yield + the expected growth rate in dividends.

This formula is the application of the "Discounted Cash Flow" (DCF) method. It is a market-oriented method that Dr. Amit discussed in detail in his testimony. Id. at 4, (EA-30).

101. Dr. Amit prepared 29 schedules (DPS Ex. 67 (EA-1) through (EA-29)) and 5 appendices (DPS Ex. 67 (EA-30) through (EA-34)), to help determine the fair rate of return on equity and the overall cost of capital for NSP-Electric.

102. Dr. Amit's analysis did not depend solely on data specific to NSP-Electric. In estimating the cost of equity for a particular utility, it is useful to perform a DCF analysis on a group of companies whose investment risk is comparable to the utility in question. Also, the goal is to estimate the required rate of return on equity for NSP-Electric, which may be slightly different than the required rate of return for NSP. Thus, Dr. Amit performed a DCF analysis not only on NSP, but also on two groups of companies that have investment risks similar to that of NSP-Electric. Id. at 5. One group consisted of electric utilities, the other of "combined" (gas and electric) companies.

103. There are many DCF models; however, the model appropriate for this proceeding is the annual DCF model. As is true for most utilities, each utility in Dr. Amit's comparison groups pays dividends every quarter. Consequently, the quarterly DCF model may appear to be appropriate. This is indeed true for nonregulated companies that pay quarterly dividends. However, the quarterly DCF model may not be an appropriate model to apply to regulated utilities. In general, public utility commissions don't accept the quarterly DCF model; specifically, the Minnesota Public Utilities Commission does not. Since the Commission's policy is publicly available information, investors incorporate this information into their stock valuations. Id. at 5-6.

104. It is important to choose a group of companies whose investment risk is similar to that of NSP-Electric. The obvious candidates are other electric companies. The universe of these companies consists of all electric utilities that are listed in the Compustat data base and meet the following two conditions: their primary Standard Industrial Classification (SIC) code is 4911 and their shares are publicly traded on one of the stock exchanges. Dr. Amit identified 62 companies meeting these criteria. He then applied three screens to identify which of the 62 companies have investment risks similar to that of NSP. The first screen he applied was the Standard and Poors (S&P) bond rating. He eliminated any company whose bond rating fell outside of the range of AA through A+ (NSP's bonds are rated AA- by S&P). As a result, only eight companies remained in the group. The second screen he applied was the beta, and the third screen was the standard deviation of price change (STDPC). Dr. Amit eliminated any company whose beta and STDPC deviated by more than one standard deviation from both the group's average beta and the group's STDPC. No company was eliminated as result of applying the beta and STDPC screens. Thus, eight companies survived all of Dr. Amit's screens. From these eight companies he eliminated Korea Electric Power Company because of the lack of data. The remaining seven companies constitute Dr. Amit's first comparison group. He referred to this group as the "Electric Comparison Group," or "ECG." DPS Ex. 67 at 7.

105. Dr. Amit's second comparison group was a group of combination electric and gas utilities. While the purpose of this proceeding is to determine the cost of equity for NSP-Electric, one cannot disregard the fact that NSP has gas operations and some non-regulated operations. When investors buy shares of common stock of NSP they invest in both the electric and gas operations of NSP (and in NSP's non-regulated operations as well). Therefore, the cost of equity for the combination group will provide additional useful information regarding NSP-Electric's cost of equity for its regulated operations. The universe of the combination group consists of all the combination utilities that are listed in Compustat data base and meet the following two conditions: their primary SIC code is 4931 and their shares are publicly traded on one of the stock exchanges. Forty-four companies met these criteria. Dr. Amit then applied the same three screens as he did for his ECG. Six companies survived those three screens. These remaining six companies (NSP is one) constitute Dr. Amit's second comparison group. He referred to this group as the "Combination Comparison Group," or "CCG." Id. at 8.

106. The ECG and CCG are the only comparison groups Dr. Amit analyzed. However, he also estimated the required rate of return for NSP. He did so because, conceptually, the goal is to estimate the required rate of return for NSP-Electric. However, since NSP-Electric is not a publicly traded company, it is impossible to estimate its required rate of return directly by conventional methods such as the DCF or Capital Assets Pricing Model (CAPM). At the same time, estimating the rate of return for NSP can provide very useful information regarding the rate of return for NSP-Electric. By any significant measure, NSP-Electric is the most significant part of NSP. In 1994, NSP-Electric contributed 78.61 percent to NSP's earnings per share. Also, in 1995 NSP-Electric's revenues were about 83 percent of NSP's total revenues. Clearly then, the required rate of return for NSP is largely influenced by the required rate of return for NSP-Electric. Id. at 8-9.

107. Dr. Amit recognized that the required rates of return for NSP and NSP-Electric may be slightly different. However, the required rate of return for NSP may be the most important information that needs to be considered in estimating the required rate of return for NSP-Electric. NSP's required rate of return is no lower than NSP-Electric's required rate of return because it is reasonable to expect that NSP-Electric is actually less risky than NSP. Id. at 9-10.

108. It is reasonable to expect that NSP is somewhat riskier than NSP-Electric because, besides electric operations, NSP has gas operations and non-regulated operations. Because of the relatively small size of the gas operations, they may not have a significant impact on NSP's cost of equity. However, it is likely that NSP's non-regulated operations have higher business risks than NSP's electric operations. Therefore, NSP is likely to be riskier than NSP-Electric. Id. at 10.

109. Dr. Amit used several measures of investment risk in his comparison group selection process. An important measure of the risk of investing in common stock is the volatility of the rate of return. This volatility can be measured by either the beta or the standard deviation of price change (STDPC). Both the beta and the STDPC focus on the variability of returns to investors. Since this variability causes investor uncertainty, the beta and STDPC measure risk directly. Both of these risk measures are derived

from modern portfolio investment theory. Dr. Amit examined other risk measures as well, including the companies' equity ratios and interest coverage to evaluate their financial risks. Id. at 10-11.

DCF Analysis by DPS

110. The DCF analysis requires a determination of expected growth rates and dividend yields. DPS Ex. 67 at 14.

111. Dr. Amit examined the past growth rates of the major financial variables and explored their implications for future growth. It should be emphasized that while the past performance of a utility is the departure point in the analysis, it is not the sole determinant of the utility's growth prospects. In particular, the rapid changes in the electric industry may make the past performance of a utility much less significant in trying to determine its future performance. Investors also consider the current and prospective conditions of the utility, as well as the trends and prospects for the industry as a whole. Id. at 16.

112. If one could reasonably assume that the expected growth rates in book value per share (BPS) are equal to their historical growth rates, then Dr. Amit would use the historical growth rate in BPS as a proxy for the expected growth rate in DPS. However, during the last 10 years both the rates of return on equity and the retention ratios were not constant for most utilities. (The retention ratio equals 1 - (Annual Dividend Paid/Annual Earnings)). Moreover, the market-to-book (M/B) ratios were usually not equal to 1.0. Consequently, the growth rates in BPS came not only from retained earnings, but also from issuances of new shares of stock. Under these circumstances, it would be inappropriate to use the historical growth rate in BPS as a sole proxy for the expected growth rate in DPS. Id. at 17.

113. Instead, Dr. Amit also considered other historical growth rates and the available information about future growth rates. "Zacks Investment Research," a respected national company, provides such information. This service compiles estimates of growth rates based on the forecasts of many investment analysts. "Value-Line" is another widely used investment service that provides information about future growth rates. Id.

The above discussion of historical growth rates explains why under normal circumstances it is necessary to examine not only BPS growth rates, but other historical growth rates as well. However, in the rapidly changing environment of the electric industry, all the historical growth rates may not be good indicators of the expected dividend growth rates. Id. at 17-18. This issue is discussed further later in this Report.

Comparison Groups

114. To estimate the required rate of return for the ECG, Dr. Amit estimated both the expected growth rate, g, and the dividend yield, y. DPS Ex. 67 at 19. It is desirable to examine both the historical and forecasted growth rates to estimate the expected growth rate for use in the DCF analysis. DPS Ex. 67 at 19.

115. Regarding projected growth rates, Value-Line provides five-year forecasts of BPS, DPS and EPS. These forecasted growth rates are 3.57 percent, 2.30 percent and 3.36 percent, respectively. The average of these forecasts is 3.08 percent. Zacks

Investment Services (Zacks) provides five-year forecasts of EPS growth rates. Since in the long run earnings per share should grow at the same rate as dividends per share, Dr. Amit used Zacks' forecasted growth rate in EPS as a proxy for the expected DPS growth rate. Zacks' average forecasted growth rate in EPS for the ECG is 3.19 percent. DPS Ex. 67 at 21.

116. Regarding Dr. Amit's best estimate of the expected growth rate for the ECG group, it is important to consider both the historical growth rates and the projected growth rates to estimate the expected growth rate of dividends. However, in this proceeding, the historical growth rates of EPS, DPS and BPS as well as the historical internal growth rates may not be good proxies for the expected dividend growth rate. In recent years competition at the wholesale level of the electric industry has been increasing throughout the country, due primarily to technological advances and to changes in federal law and regulation. Both nationally and in Minnesota, state legislators and regulators are feeling pressure from large industrial electricity customers and non-utility electricity generators to restructure the electric industry to allow competition at both the wholesale and the retail level. For example, the 1992 Energy Policy Act (EPAct) encourages more vigorous competition in the wholesale level. Another example is the Federal Energy Regulatory Commission's (FERC) 1996 Orders 888 and 889 that require utilities to provide equal open access to their transmission lines. Clearly the equal open access provision would enhance competition in the wholesale electricity market. It is very possible that in the near future utilities will look very different than the well known vertically integrated utilities of today. It is not unlikely, for example, that today's vertically integrated utilities will be divested into three independent entities: generation, transmission, and distribution. Additionally, competition in the retail electric market is being seriously considered by many states in general, and by Minnesota in particular. The exact future structure of the electric industry could not be accurately predicted at this point. However, Dr. Amit concluded with certainty that the electric industry will become more competitive in the future and a future electric utility will look different than today's typical vertically integrated utility. DPS Ex. 67 at 22-23.

117. Given the emerging changes in the electric industry, Dr. Amit decided the best estimate of the expected growth rate in DPS for the ECG is based on the projected growth rates only. The Value Line five year projected growth rate in DPS of 2.30 percent is much lower than the Value Line projected growth rates in EPS and BPS, respectively. As was noted earlier, in the long run, DPS, EPS and BPS should all grow at the same rate. Therefore, Amit decided the Value Line projected DPS growth rate is not a good proxy for the expected DPS growth rate. The remaining Value Line projected growth rates are 3.36 percent and 3.57 percent for EPS and BPS, respectively. Zack's EPS projected growth rate is 3.19 percent. In view of these projections, Dr. Amit's best point estimate of the expected growth rate in DPS for the ECG is the average of the remaining three projected growth rates. This average is 3.37 percent. Dr. Amit's forecasted range for the DPS expected growth rate is from a low of 3.19 percent to a high of 3.57 percent. DPS Ex. 67 at 23-24.

118. Regarding the dividend yield for the ECG, the companies in this group may raise their dividend rates in different quarters. For some of these companies the current

dividend yield may not change over the next one or two quarters, then increase in subsequent quarters. For other companies, the dividend yield may remain constant for three or four quarters. Amit concluded the most appropriate estimate of the expected annual dividend yield for the ECG can be derived as follows:

Most current annualized dividend yield x (1 + .5g), where g is the expected growth rate.

119. The current dividend yield is based on the most recent available four weeks' closing prices (7/25/96 - 8/27/96 as of the time Dr. Amit prepared his Direct testimony). DPS Exhibit 67 at (EA-15) provides the dividend yields used in Dr. Amit's DCF analysis. After applying the growth-rate adjustment shown above, the average expected dividend yield for the ECG is 5.57 percent. Based on the range of the expected growth rates, the range for the expected dividend yield is from a low of 5.56 percent to a high of 5.58 percent. DPS Ex. 67 at 24.

120. Based on an expected growth rate of 3.37 percent and an expected dividend yield of 5.57 percent, the required rate of return on common equity for this group is 3.37 + 5.57 = 8.94 percent. Based on the range of the expected growth rate, the range of the required rate of return is from a low of 8.75 percent to a high of 9.15 percent. These estimates do not include flotation costs. DPS Ex. 67 at 25.

121. As in the case of the ECG, Dr. Amit analyzed both the historical and forecasted growth rates to arrive at the expected growth rate for the CCG. DPS Ex. 67 at 25.

122. As in the case of the ECG, the applicable growth rates are the BPS, DPS and EPS growth rates. The ten-year historical growth rates are 3.50 percent, 4.10 percent, and 2.13 percent for BPS, DPS and EPS, respectively. See DPS Ex. 67 at (EA-27). The five-year historical growth rates are 3.20 percent, 2.54 percent and 2.50 percent for BPS, DPS and EPS, respectively. See DPS Ex. 67 at (EA-27). The average of all the historical growth rates, including the internal growth rate, is 2.95 percent. DPS Ex. 67 at 26.

123. As in the case of the ECG group, Dr. Amit used Value-Line's projected five-year growth rates in BPS, EPS and DPS and Zacks' projected five-year growth rate in EPS. The average of Value-Line's projected growth rates is 3.02 percent and the average of Zacks' EPS growth rates is 2.95 percent. DPS Ex. 67 at 26, (EA-28).

124. As in the case of the expected growth rate for the ECG, Dr. Amit's best estimate of the DPS expected growth rate for the CCG is based on the projected growth rates only, because of the emerging changes in the electric industry. Zack's average projected five-year growth rate in EPS is 2.95 percent. Value Line projected growth rates are 3.50 percent, 1.88 percent and 3.50 percent for EPS, DPS and BPS, respectively. Since in the long run, the growth rates in EPS, DPS and BPS should be the same, the DPS projected growth rate of 1.88 is too low to be an appropriate proxy for the long-run DPS expected growth rate. Therefore, Dr. Amit's best point estimate for the expected dividend

growth rate is the average of Value Line projected EPS and BPS growth rate and Zacks projected EPS growth rate. This average is 3.32 percent. Dr. Amit's estimate of the range of the growth rate is from a low of 2.95 percent (Zack's projected growth rate) to a high of 3.50 percent. (Value Line projected growth rates in EPS and BPS). DPS Ex. 67 at 27.

125. As in the case for the Electric Comparison Group, Dr. Amit used the most current annual dividend rate for the group and the average closing prices for the period 7/25/96 - 8/27/96. See DPS Ex. 67 at (EA-29). The average dividend yield for the group is 6.41 percent. This average dividend yield must be adjusted for the expected growth rate. However, since some utilities may have just raised their dividend rates, while others may raise them in the next one or two quarters, a practical way to adjust the dividend yield is to raise it by one-half of the growth rate. Thus, the expected dividend yield for the group is 6.41 x (1 + 0.0332/2) = 6.52 percent, and based on the range of the growth rate, the expected dividend yield ranges from a low of 6.51 percent to a high of 6.53 percent. DPS Ex. 67 at 28.

126. Dr. Amit's best point estimate of the required rate of return for the CCG is the sum of the dividend yield and the expected growth rate, which is 6.52 + 3.32 = 9.84 percent. Dr. Amit's estimated range for the required rate of return is from a low of 9.46 percent to a high of 10.03 percent. DPS Ex. 67 at 28.

DCF Analysis for NSP

127. Dr. Amit's estimate of the expected growth rate for NSP is based on projected growth rates from Value-Line and Zacks.

128. As in the case of the ECG and CCG, Dr. Amit used Value-Line's and Zacks' projected five-year growth rates. Value-Line's projected growth rate for BPS, DPS and EPS are 4.50 percent, 2.00 percent and 4.50 percent, respectively, and Zacks' projected five-year growth rate for EPS is 3.50 percent. See DPS Ex. 67 at (EA-28). Eliminating Value Line DPS expected growth rate for the same reason as before, Dr. Amit's best estimate of NSP's expected growth rate is the average of his selected Value-Line growth rates and Zacks growth rate. This average is 4.17 percent. DPS Ex. 67 at 29.

129. Dr. Amit's best point estimate of NSP's expected growth rate is 4.17 percent. His best estimated range of the expected growth rate is from a low of 3.50 percent to a high of 4.50 percent. DPS Ex. 67 at 29.

130. Again, Dr. Amit used the most current annualized dividend rate and the most recently available four-weeks' average closing prices to calculate the expected dividend yield for NSP. DPS Exhibit No. 67 at (EA-29) shows the calculation of the dividend yields. The dividend yield for NSP is 6.06 percent. As in the case of the other groups, Dr. Amit increased this yield by one-half of the growth rate to allow for a dividend increase in the next four quarters. Thus, the expected dividend yield for NSP is 6.06 x (1 + .0417/2) = 6.19 percent. Based on the range of the expected growth rate, the range of NSP's expected dividend yield is from a low of 6.17 percent to a high of 6.20 percent. DPS Ex. 67 at 30.

131. Summing the expected dividend yield and growth rate yields a required rate of return for NSP of 6.19 + 4.17 = 10.36 percent. Based on the range of the expected growth rate, the range for NSP's required rates of return is from a low of 9.67 percent to a high of 10.70 percent. DPS Ex. 67 at 30.

DPS Recommendation on Rate of Return

132. In addition to his DCF analysis for the ECG, CCG and NSP, Dr. Amit performed an analysis using the Capital Asset Pricing Method (CAPM) to get additional information about the required rate of return on common equity for NSP-Electric. This analysis confirmed that NSP's required rate of return on equity is not higher than 10.43 percent, not including issuance costs. DPS Ex. 67 at 31, 35.

133. Based on Dr. Amit's DCF analyses of ECG, CCG and NSP, the required rate of return for NSP-Electric is in the range of 8.75 percent to 10.70 percent. The low end of the range may not be appropriate in view of other current securities' yields. For example, mortgage-backed securities such as GNMA-8 percent have a current yield of 7.82 percent and utility 25/30 year A rated bonds have a current yield of 7.78 percent. Id. at 35.

134. The most direct information regarding the required rate of return for NSP-Electric is provided by Dr. Amit's DCF estimate for NSP. Based on Dr. Amit's DCF analysis of NSP, the required rate of return on NSP's common equity is from a low of 9.67 percent to a high of 10.70 percent. This estimated range is supported by Dr. Amit's CAPM analysis on NSP. Also, based on his DCF analysis of NSP, Dr. Amit's best estimate for the cost of common equity for NSP-Electric is 10.36 percent. Additionally, based on his DCF analyses of ECG, CCG and NSP and his CAPM analysis of NSP, Dr. Amit concluded that NSP-Electric's required rate of return on equity does not exceed 10.70 percent. DPS Ex. 67 at 35-36.

135. However, Dr. Amit did not recommend a required rate of return on equity of 10.36 percent for NSP-Electric. He adjusted the rate of return of 10.36 percent to allow for the issuance of new shares of common stock without causing dilution. Due to issuance costs, the price paid by an investor for a new share of common stock is less than the revenues received by the company. These issuance costs must be recognized by adjusting the required rate of return. DPS Ex. 67 at 36. Dr. Amit demonstrated the need for an issuance-cost adjustment in DPS Ex. 67 at (EA-33).

136. After adjusting for issuance costs, Dr. Amit's best point estimate for the required rates of return on common equity for NSP-Electric is 10.49 percent. Dr. Amit also concluded that the required rate of return on common equity for NSP-Electric, including issuance cost, does not exceed 10.83 percent. Id.

137. Based on Dr. Amit's analysis, the ALJ adopts a rate of return of 10.49 percent on NSP-Electric's common equity capital and an overall rate of return of 8.55 percent on NSP-Electric's total capital.

DISCUSSION

Two witnesses made recommendations on the rate of return to be used in assessing the pre-merger revenue requirement: Mr. Pender for NSP and Dr. Amit for the Department. They agreed on appropriate capital structure, the cost of debt and preferred stock. The only aspect of rate of return in controversy is the reasonable return on equity. The difference in the two recommendations stems from differences in the method of analysis and universal data considered by the two witnesses. As in recent NSP rate cases, the Company is critical of the DPS witness's exclusive reliance on DCF-based calculations and what it believes to be a conscious disregard of independent non-DCF estimates and other "reality checks". It urges the Commission to keep in mind the added risks that the merger transaction places on shareholders, in addition to assessing the pre-merger revenue requirements. These additional risks are those associated with attempting to achieve savings estimates and with operating under a four-year rate freeze.

The Company maintains that the 11.47% return on equity is supported by risk premium, capital asset pricing, and modified discount cash flow studies, and is consistent with returns allowed in other recent cases. It notes the Public Service Commission of Wisconsin recently set rates for NSP(W) for 1997 using a return of 11.3%, and for WEC at 11.8%. In a generic proceeding decided in late November, the California PUC set rates for 1997 for the major utilities in that state at 11.6%.

The Company contends that the DCF model used by the DPS produces results so low that most of the calculations were disregarded by its own witness. It notes that Dr. Amit's recommendation was based on an NSP - specific calculation that ignored the fact that dividends are paid quarterly, not annually, and that when correcting for this deficiency, Amit's result would support a return on equity as high as 11.07%. Even at that level, however, the results are at odds with all of the other methods of estimating the costs of equity which are independent of the DCF method.

Using Dr. Amit's testimony that the pressure and pace of structural change in the electric industry is increasing investor risk as a starting point, Mr. Pender for NSP agreed and described some of the important changes affecting the cost of equity, noting that 28% of the nation's major electric companies have experienced downgrading of their bonds in the last few years. He noted NSP's bonds were downgraded by Moody's in 1994. The reality of competition from independent power producers must be noted, along with new sources of power now up for competitive bid and FERC Order 888's ensuring open access on transmission lines. Utilities are also experiencing growing financial risks associated with long-term power purchases. Retail customer choice and a risk of a stranded investment are issues at both the federal and state levels regarding utility regulation.

Under the unique circumstances of this case, which is not a rate case but an investigation into pre-merger revenue requirements to assist the Commission in a decision about merger conditions such as a rate decrease and a four-year rate freeze, NSP believes it is appropriate to recognize that a rate freeze increases the risk assumed by shareholders. A rate freeze is a feature not normally appended to a rate case, and it obviously increases the risk to the shareholder. However, neither this risk, nor the risk of not realizing the estimated merger savings, was taken into account by Mr. Pender or Dr. Amit. The Company urges the Commission to recognize that it may not be necessary or appropriate to set rates at a level that ignores such unique circumstances and risks as those presented by the merger.

On behalf of NSP, Mr. Pender notes that both dividend yield and dividend growth estimates that could be used as the basis for a DCF estimate for the return on equity for NSP in this proceeding and for the comparable group were subject to wider ranges of estimates than is normally the case. The Company argues that Dr. Amit also performed a DCF analysis on two comparable groups and concluded that the results there were too low and that they indicated an insufficient premium over current bond yields, which serves to corroborate Mr. Pender's position. Mr. Pender did demonstrate a modified DCF calculation for NSP that yielded results more in line with the estimates he made using other methodologies. Pender used growth estimates presented in Dr. Amit's testimony, giving two-thirds weight to Amit's NSP growth and one-third weight to his competitive industry growth rate, yielding a DCF result of 11.67%.

One of the methods used by Mr. Pender to estimate the costs of equity was a Capital Asset Pricing Model (CAPM), which is independent of the DCF method. CAPM analysis not only provides an estimate of cost, but also can serve as a "reality check" on DCF-based estimates. The CAPM adds a measure of a stock's systematic risk to a risk-free cost of money. For the risk-free rate, Mr. Pender used average yields on long-term US Treasury bonds. He then added the systematic risk, which is the product of market risk premium (using the historical premium contained in the Ibbotson and Sinquefield study measuring the period since 1926) using the beta published in Value Line. Pender calculated a cost of equity of 11.18% for the comparable group and 11.44% for NSP, prior to application of a flotation cost adjustment.

Pender also estimated the cost of equity using the equity risk premium method, which involves comparing historical returns on 30-year Treasury bonds to returns on comparable utility stocks for a 20-year period to estimate the risk premium. The risk premium is then added to recent bond interest rates to estimate the appropriate return on equity. Pender's study indicated a return on equity of 12.35% prior to adjustment for flotation costs.

Pender calculated a flotation cost of 15 basis points to be added to the cost of equity calculations of his various methods, which is precisely the adjustment made by the PUC in NSP's last rate case. Based on his CAPM analysis for NSP of 11.6%, his risk premium of 12.5%, allowed returns from other cases of 11.7% and 11.3%, and a modified DCF calculation of 11.7%, Mr. Pender concluded that the 11.47% allowed in NSP's last rate case remains reasonable today.

After taking into consideration the argument presented for maintaining the present return on equity for the purposes of this proceeding, the Administrative Law Judge has decided to recommend a reliance on the DCF methodology utilized by DPS witness Dr. Eilon Amit.

There are several unsettled empirical issues related to the CAPM, some of which are discussed in DPS Ex. 67 at (EA-34). However, even if one is willing to disregard these issues, the Judge is persuaded by the Department's contention that Mr. Pender's application of the CAPM is flawed for the following reasons: (1) the risk premium he used is inappropriate and (2) the betas he used for NSP and the comparison group may not be the appropriate betas. DPS Ex. 67 at 42.

Regarding the issue of the risk premium, Mr. Pender used historical risk premium of equity over long-term U.S. Treasury bonds. He used the Ibbotson and Sinquefield Study to conclude that the average risk premium of equity over U.S. bonds over the period 1926-1994 is 7.0 percent. NSP Ex. 45 at 26, 27. The use of historical risk premium in the CAPM is suspect because it assumes that the equity-over-bond risk premium is not related to the specific conditions in the capital markets. Since the risk factors associated with equity investment are different than the risk factors associated with investment in a U.S. Treasury bond, changes in the capital markets may result in changes in the relative investment risks of equity versus U.S. Treasury bonds. Thus, changes in the capital markets may result in changes in the risk premium. In other words, the risk premium varies with changes in the capital markets and the average historical risk premium may not be a good proxy for the current risk premium. In fact, using historical average risk premium is equivalent to using historical averages of required rates of return to estimate NSP's current required return on equity. As shown in Dr. Amit's testimony, the risk premium may range from a low of 4.31 percent to a high of 5.19 percent. Using the upper end of this range in combination with Mr. Pender's betas, and the risk free rate, would result in NSP's CAPM cost of equity of 10.17 percent (6.54 + .7 (5.14)) and a comparable group CAPM's cost of equity of 9.93 percent (6.54 + .66 (5.14)). DPS Ex. 67 at 42-43.

Regarding the issue of the betas, there are different ways to estimate betas. For example Value Line estimates NSP's beta to be .70, while Compustat estimates NSP's beta to be .441. Clearly, the results of the CAPM are highly influenced by the value of beta. Using the Compustat beta for NSP in combination with Mr. Pender's inappropriate historical risk premium of 7.0 percent would result in NSP's required rate of return of only 9.63 percent. Since Compustat's betas are usually smaller than the Value Line beta, applying them to Mr. Pender's comparison group will result in a much lower CAPM required rate of return for this group as well. Id. at 43.

Mr. Pender calculated the average annual holding period returns of double A utility stocks and 30 year treasury bills over the period 1976 through 1995. He then added the difference in the average returns (the risk premium) to the current yield on 30 year treasury bonds to arrive at an estimated rate of return of 12.35 percent. The main flaw of Mr. Pender's risk premium analysis is that it is based on the assumption that the risk premium is the same regardless of market conditions. Again, as in the case of his CAPM application, Mr. Pender assumed that the relative risk of double A utility stock investment and 30 year treasury bond investment is independent of market conditions. This assumption is not supported by either empirical or theoretical studies. In fact, Mr. Pender himself stated: "It is the selection of a historical period of time that is the most subjective aspect of the Equity Risk Premium approach." Mr. Pender also argues that "the historical period of time must include at least one `market cycle' of both favorable and unfavorable conditions in the stock and bond markets." Thus, Mr. Pender himself submits that the risk premium may depend on the particular market conditions. DPS Ex. 67 at 44-45.

The ALJ is persuaded that the risk premium in this proceeding should reflect the current market conditions, rather than reflecting a 30 year historical average. For example, if we look at the 10 year period, 1976 through 1985, the average returns on double A utility stocks and 30-year treasury bills were 17.15 percent and 8.86 percent, respectively, and the average risk premium for this period was 8.29 percent. However, for the 10 year period 1986 through 1995 the average return on stocks went down to 14.90 percent, while the average return on treasury bills went up to 11.61 percent, producing a risk premium of only 3.29 percent. The point of this example is clear: the average risk premium over long periods may be higher or lower depending on the market conditions over the time period in question. Id.

The return of 12.35 percent indicated by Mr. Pender's risk premium analysis is inappropriate as an estimate for NSP's required rate of return on equity. The 12.35 percent is the result of applying a historical 30 year average risk premium. Since the risk premium depends on the current market conditions, the application of historical average risk premium is inappropriate. For example, using Mr. Pender's data for the period 1986 through 1995 would produce a required rate of return of only 9.86 percent (not including issuance costs). Id. at 45-46.

Mr. Pender calculated the average of the rates of return on common equity for electric utilities for all Commissions' Orders issued in 1995, and updated the information for 1996. NSP Ex. 45 at 36; NSP Ex. 46 at 20. The 1995 average is 11.66 percent; the 1996 average is 11.3 percent. Id. However, this method is inappropriate to estimate NSP's current required rate of return on equity capital for two reasons: (1) the rates of return reviewed by Mr. Pender are historical, not current rates of return, and (2) the utilities appearing on Mr. Pender's list (NSP Ex. 45 at (PEP-1), Schedule 13) may not have investment risk similar to NSP-Electric's investment risk. DPS Ex. 67 at 46.

The rates of return authorized in 1995 are most likely to reflect the market conditions that existed in 1994 and early 1995. Since rates of return on equity are very sensitive to the prevailing market conditions, the return authorized in 1995 may not be a good estimate of the returns on common equity expected in late 1996. Id. Even the 1996 rates of return are likely based on market conditions as they existed in late 1995 and early 1996. Tr. Vol. 4 at 132. Moreover, it is interesting to note that the average most relevant to this proceeding (because it is the most recent one) is the average for the third quarter in 1996. This average return according to Mr. Pender is "just under 11.00 percent." DPS Ex. 68 at 19.

It is noted that the majority of the utilities in Mr. Pender's Schedule 13 do not belong to Mr. Pender's comparison group. Compare NSP Ex. 45 at PEP-1, Schedule 13 with id. at PEP-1, Schedule 9. Moreover, Mr. Pender testified that he did not perform any analysis to determine whether the utilities in his list were risk comparable to NSP. Tr. Vol. 4 at 16. Therefore, many of the returns shown in Mr. Pender's Schedule 13 may reflect returns allowed for utilities with higher, not comparable, investment risk to

NSP's, and should not be used to estimate NSP-Electric's required rate of return on common equity capital.

Mr. Pender's modified DCF analysis is flawed. He estimated an expected growth rate for NSP of 5.45 percent by taking a weighted average of Dr. Amit's market portfolio growth rate of 8.38 percent (one-third) and Dr. Amit's NSP growth rate of 4.17 percent (two-thirds). His resultant rate of return is 11.67 percent. Mr. Pender's use of the specific weights and the growth rate of 8.38 percent are suspect. The 8.38 percent growth rate came from Dr. Amit's CAPM analysis to estimate the required rate of return for the Value Line industrial composite portfolio. Tr. Vol. 5 at 84-85. That rate has no relationship to appropriately performed DCF analyses. Id. at 85. Mr. Pender's "modified" DCF analysis should be discounted accordingly.

Mr. Pender used CAPM, Risk-Premium analysis, and authorized rates of return analysis to estimate NSP-Electric's required rate of return, and concluded that it is in the range of 11.30 percent to 12.50 percent. Therefore, he concluded that NSP's currently authorized rate of return of 11.47 percent is reasonable. Given the flaws of the CAPM and the Risk-Premium methods, the ALJ believes it is inappropriate to rely on them to estimate NSP-Electric's required rate of return on equity. Mr. Pender's application of the 1995 and 1996 authorized rates of return is inappropriate for the purpose of estimating NSP-Electric's required rate of return on equity in this proceeding as well. NPS's recommendations on rate of return are based on historic, rather than (preferred) current market conditions. The DCF methodology utilized by the DPS, and its results herein, are appropriate for approval in this proceeding.

Intervention by the Prairie Island Indian Community (PIIC)

138. The PIIC is concerned that, in connection with deciding on the merger proposal, the Minnesota Public Utilities Commission require that NSP not be allowed to seek an increase in rates during the freeze period to fund its alternate siting obligations. The Community asserts that approval of the merger without such a condition would be contrary to the intent of the freeze and not in the public interest.

139. In Response to the PIIC, the Company notes that the issue raised is outside the scope of this segment of the contested case (pre-merger revenue requirements). As to the merits of the issue, the Company argues that the issue of costs associated with alternate siting for dry cask storage of Prairie Island's nuclear waste elsewhere in Goodhue County is premature in that it depends on the result of pending litigation. NSP argues that if such costs are incurred, then it will decide whether to ask for consideration of whether they qualify as an exception to the rate freeze.

140. The Administrative Law Judge finds that if NSP incurs costs for construction of alternate storage sites during the freeze period, it is consistent with its Petition in this matter that the Company could file a request for rate relief under one of the exceptions for which it seeks approval in this proceeding. It is

within the jurisdiction of the Judge to make this Finding because the record shows that costs were budgeted in 1996 related to the construction of an alternate storage facility and the applicability of exceptions to the rate freeze has been raised by the Company and others in the context of other issues.

Revenue Requirement Summary

141. As a result of the preceding Findings regarding cost of capital, rate base, and test year income, the revenue surplus of Northern States Power Company for the test year is $3,481,000, calculated as follows:

Rate Base	$2,496,646,000
Overall Rate of Return (Including 10.49% Cost of Equity)	8.55%
Required Operating Income (Rate Base x 8.55%)	213,463,000
Test Year Income	215,500,000
Operating Income Surplus	2,037,000
Gross Revenue Conversion Factor	1.708817
Gross Revenue Surplus	3,481,000

In the above computations, the Administrative Law Judge used the rate base proposed by NSP. He used also the test year income proposed by the Company as a starting point, and added to that figure $394,000 (which "grosses up" to $673,000 when multiplied by the revenue conversion factor) to reflect his Finding that the costs associated with providing wholesale service, which exceeded revenues by that amount, are not recoverable from Minnesota retail ratepayers.

Concepts to Govern

142. It is the intention of the Administrative Law Judge that the concepts set forth in the Findings of Fact should govern the mathematical and computational aspects of the Findings of Fact and Conclusions. Any mathematical or computational errors are unintentional and should be corrected to conform to the concepts expressed in the Findings of Fact and Conclusions.

Based upon the foregoing Findings of Fact, the Administrative Law Judge makes the following:

CONCLUSIONS

1. The Public Utilities Commission and the Administrative Law Judge have jurisdiction over the subject matter of this hearing pursuant to Minn. Stat. Ch. 216B and §§ 14.57-14.62 and Minn. Rules Pt. 1400.5100-.8300.

2. Any of the above Findings of Fact more properly considered Conclusions of Law are hereby adopted as such.

3. The Commission gave proper notice of the hearing in this matter, has fulfilled all relevant substantive and procedural requirements of law or rule and has the authority to take the action proposed.

4. The quantum of proof necessary to establish the facts supporting the proposals of the parties in this matter is proof by a preponderance of the evidence.

5. The appropriate test year for use in this proceeding is the 12-month period between January 1, 1996 and December 31, 1996, adjusted for known pre-merger changes in 1997.

6. The appropriate capital structure for use in this proceeding is 39.76% long-term debt, 5.30% short-term debt, 6.56% preferred stock and 48.38% common equity.

7. The cost of long-term debt of the Company for use in this proceeding is 7.08%.

8. The cost of short-term debt to be used in determining the Company's cost of capital is 5.80%.

9. The Company's cost of preferred stock to be used in determining its cost of capital is 5.14%.

10. The appropriate dividend yield component in cost of equity for the Company during the test year is 6.19%.

11. The appropriate growth rate component in the Company's cost of equity for the test year is 4.17%.

12. It is appropriate to adjust the return on equity by 13 basis points (.13%) to allow for the issuance of new shares of common stock during the test year without causing dilution.

13. The appropriate cost of common equity for NSP in this proceeding is 10.49%.

14. The appropriate overall rate of return to be allowed the Company in this proceeding is 8.55%.

15. It is appropriate to reject the Company's proposal to recover $673,000 in costs associated with providing wholesale service from the retail ratepayers in this case.

16. It is appropriate to reject the proposals of the DPS and OAG for adjustments to the Company's proposals regarding allocations and expenses in this matter except for the proposal noted in the preceding Conclusion. The Company's Step 2 (69 employees) and Step 3 (NTS, Project 2000) adjustments are appropriate.

17. It is appropriate to set NSP's average rate base for the test year at $2,496, 646,000.

18. It is appropriate to set NSP's test year income at $215,500,000.

19. The appropriate revenue surplus for Northern States Power Company during the test year is $3,481,000.

THIS REPORT IS NOT AN ORDER AND NO AUTHORITY IS GRANTED HEREIN. THE PUBLIC UTILITIES COMMISSION WILL ISSUE THE ORDER OF AUTHORITY WHICH MAY ADOPT OR DIFFER FROM THE FOLLOWING RECOMMENDATION.

Based upon the foregoing Conclusions, the Administrative Law Judge makes the following:

RECOMMENDATION

IT IS HEREBY RECOMMENDED that the Public Utilities Commission include in its Order in this proceeding a determination that Northern States Power Company has a pre-merger annual retail electric revenue surplus of $3,481,000 in the state of Minnesota.

Dated this 14th day of February 1997.

RICHARD C. LUIS
Administrative Law Judge

Reported: Angie Threlkeld, Shaddix and Associates

Transcript Prepared

<u>NOTICE</u>

Pursuant to Minn. Stat. § 14.62, subd. 1, the Agency is required to serve its final decision upon each party and the Administrative Law Judge by first class mail or as otherwise provided by law.

<u>MEMORANDUM</u>

This Report makes no recommendation on approval or disapproval of the proposed merger, nor does it attempt to determine the level of rate reduction (if any) or the length of a rate freeze. These issues are outside the scope of this portion of the contested case proceeding, and must be decided by the Commission after consideration of all the factors it deems relevant, consistent with the public interest.

RCL

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[1] The period for the rate freeze has been specified at various times in this proceeding as through calendar year 2000. The four year period ending December 31, 2000 began January 1, 1997. Whether the proposed freeze ends on December 31, 2000 or four years after the merger is approved and rates are reduced has not been clarified.